STATE OF VERMONT

PUBLIC SERVICE BOARD

Docket No. 7533

Investigation into Implementation of Standard)
Offer Prices for Sustainably Priced Energy)
Enterprise Development Resources)

REDLINED REBUTTAL TESTIMONY OF
JOHN DALTON
ON BEHALF OF THE VERMONT PUBLIC SERVICE BOARD

NOVEMBER 27~~2~~, 2009

Summary: The purpose of Mr. Dalton's rebuttal testimony is to provide a foundation for the cash flow model and the renewable generation technology cost, performance, tax and financing assumptions that will be used by the Board to make its price determinations for this Docket. Mr. Dalton reviews the changes that have been made to the cash flow model that was used to assist the Board in making the initial price determinations in Docket 7523. He then recommends renewable generation technology cost, performance, tax and financing assumptions and identifies the standard offer prices that result when these assumptions are applied to the cash flow model.

I. INTRODUCTION

Q. Are you the same John Dalton that submitted prefiled Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. In this rebuttal testimony I review the changes that have been made to the financial pro forma model that was used by the Board in Docket 7523 to evaluate the reasonableness of the legislatively proposed Standard Offer prices. I also recommend cost, performance, tax and financing assumptions for each of eligible standard offer program renewable generation technologies and then identify the standard offer prices that result when these assumptions are applied to this model.

However, prior to this I review the market response to the initial Standard Offer prices adopted by the Board in its September 15 Decision in Docket 7523. This market response provides insights regarding the reasonableness of these initial prices.

II. REVIEW OF MARKET RESPONSE

Q. Please review the level of market response to these initial standard offer prices.

A. Table 1 reviews the number of applications received and the kW offered by these proposed projects. As can be seen, biomass and solar PV projects exceeded the 12.5 MW technology-specific cap outlined by the Board's September 30, 2009 Order in Docket 7533. A lottery was conducted for these two technologies to determine applicants' position in the queue and whether they would be awarded contracts under this technology-specific cap.

Table 1: Applications Received on the First Day

	Number of Applications	Total Capacity (kW)	Average Size (kW)
Biomass	10	15,703	1,570
Farm Methane	14	3,045	218
Hydroelectric	9	7,747	861
Landfill Gas	3	1,710	570
Solar PV	196	171,923	877
Wind	6	8,702	1,450

Q. How do you interpret the significant response by solar PV projects?

A. Almost 200 applications offering 172 MW of solar PV capacity suggests that the interim price for solar PV is too high. However, caution needs to be exercised when evaluating these results. The standard set by the Vermont Energy Act of 2009 (Act) is "to ensure that the price provides sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive." (Sec. 4. 30 V.S.A.§8005 (b)(2)(B)(i)(III)) Therefore, the ultimate test of the reasonableness of this price is what percent of these projects are ultimately commissioned.

Q. Why wouldn't a high proportion of these projects ultimately be commissioned?

A. A significant proportion of these PV projects may not be commissioned if PV module prices don't decline at the rates anticipated by market participants.

Solar PV prices have decreased significantly in 2009 and are expected to continue to decline. (Prefiled Testimony of Jason S. Gifford, p. 8) Consequently, it is unlikely that project developers locked in their PV module costs. I expect that many effectively have allowed these costs to "float" with the expectation that they will continue to decline.

The Standard Contract facilitates this behavior by allowing generators to receive a full refund of the $10/kW security deposit if they voluntarily withdraw from the queue within 12 months. In this way the Standard Contract can be viewed as providing developers with a free option to develop a project and sell power at the solar PV contract price of 30 cents/kWh. Under such an arrangement, developers can file an application for a standard offer contract and pursue project development; and if PV prices decline to levels that provide the developers' target return then they continue to pursue project development. For a technology such as solar PV where prices are projected to decline by up to 50% in 2009 such behavior can be expected. Therefore, this significant market response should not be viewed as definitive proof that the interim standard offer price is too high since if PV prices don't decline at anticipated rates a significant proportion of these PV projects may not be commissioned.

Q. Are you recommending that the Board not consider this level of market response when evaluating the reasonableness of the Standard Offer price for PV projects?

A. No, I am not. I am suggesting that caution should be applied when interpreting these results. The PV sector is characterized by rapid technological change and significant swings in supply and demand, this makes estimating the appropriate standard offer prices more difficult. The level of market response clearly suggests that the market believes that the price may be higher than required. Nonetheless, if market conditions change in ways that are not anticipated (i.e., PV prices don't decline as anticipated) then significant project attrition can be expected. I have reflected this uncertainty in my PV pricing recommendations.

III. Structural Changes to the Model

Q. Please review the process that you used to solicit comments on the cash flow model that will be used to help establish standard offer prices.

A. I first sent an email to all parties that registered to receive emails regarding this docket, requesting that they identify possible structural changes to the cash flow model. I received three proposed changes all of which were reviewed in my Direct Testimony. Subsequently, a workshop was held on November 5th to discuss structural changes to the model. Prior to the workshop I distributed a draft agenda outlining proposed structural changes to the model and requested that parties identify any additional changes that they would propose. At the workshop several additional changes to the model were proposed.

I then modified the model to reflect comments received at the workshop and Mr. Becker modified the tax depreciation schedule. I then distributed a copy of the model to Mr. Becker of the Department of Public Service (Department) and Mr. Karcher who is testifying on behalf of Renewable Energy Vermont (REV). Mr. Becker commented on and assisted with the development of the original cash flow model and Mr. Karcher offered a number of substantive comments during the workshop.

Mr. Karcher offered a number of changes that improved the organization and overall structure of the model which I accepted. I subsequently received additional comments from Mr. Karcher and made many of these changes. In one instance, I sought clarification from Tony Kvedar of Green Mountain Power Corporation who was the original developer of the model.

Q. What are the structural changes that you made to the cash flow model that was used in the initial price determinations?

A. Nine substantive changes were made to this cash flow model:

(1) allow a portion of the contact price to escalate with inflation;

(2) modify how property taxes are calculated to conform to the methodology recommended by the Vermont Department of Taxes;

(3) allow for annual output degradation which is important for PV projects;

(4) modify how the investment tax credit (ITC) basis is calculated;

(5) revise how the ITC is considered when establishing the appropriate debt and equity contributions;

(6) calculate the loan term based on the input assumptions regarding the term of the loan;

(7) modify the tax depreciation schedule to allow the user to follow and track the depreciation treatment;

(8) modify the model structure to provide a place to input all major project development, construction and financing costs, when appropriate; and

(9) add an instructions sheet which provides a brief overview of steps that need to be followed to "solve" the model.

All of these changes were discussed at the November 5th workshop, except one which was proposed after the workshop by Mr. Karcher. There was general agreement among those participating in the workshop that these changes were appropriate and would enhance the ability of the model to estimate the appropriate standard offer prices. These changes are intended to more accurately model cash flow impacts and don't necessarily have a bearing on how these different generation technologies should be modeled, e.g., whether it is appropriate to escalate a portion of the standard offer contract price by an inflation index. A separate conference call was held to discuss changes that applied to the farm methane model given that there were parties that were specifically interested and offered expertise regarding farm methane projects.

Q. Please review the structural changes that have been made to the cash flow model that you are using for this pricing analysis.

The first change that I made was to allow a portion of the standard offer price to escalate with inflation to provide additional cash flows to cover increasing operating expenses that resulted in negative cash flows in some instances. Allowing a portion of the contract price to escalate by inflation should address this issue, result in more stable debt service coverage ratios and reduce operating cost risks for generators. Having a contract price that escalates over time also reduces the front-loading (i.e., a price which conveys greater value to the supplier in the initial years of the contract) and as a result reduces the risks to consumers from overpayments in the initial years should the project fail to perform or its output decline in the later years of the contract term when its output is expected to be more valuable.

The second change that I made to the cash flow model was to modify how property taxes are calculated. This change follows the methodology outlined by the

Vermont Department of Taxes representative to the Cost Analysis Subgroup. Specifically, the property's assessed value is established by calculating the net present value of the project's annual EBITDA (Earnings before Interest, Taxes, Depreciation and Amortization) value using a property tax capitalization rate (i.e., the project's weighted average before tax cost of capital, depreciation charge factor and property tax factor. A similar approach is used by Green Mountain Power Corporation to establish the property tax liability for its facilities. The appropriate tax rates (i.e., 1.35% for the educational tax rate and 0.43% for the municipal tax rate) are then applied to this property tax basis to establish the annual property tax amount. I also changed how property taxes were established over time. Previously, they were assumed to escalate with inflation. This fails to reflect that as the generation asset depreciates and its remaining useful life diminishes its value declines. Therefore, I assumed that annual property tax charges changed by the product of the inflation rate and the depreciation in value of the generation asset which is assumed to follow the decline in the asset's useful life (i.e., 4% per year for an asset with a useful life of 25 years).

The third change that I made was to reflect the output degradation for solar PV projects. The model was modified to allow the user to specify the appropriate output degradation rate. This feature is only likely to be used for PV projects and reflects the fact that the PV module weathers and its performance declines over time.

The fourth change made to the cash flow model was to address an error in how the ITC basis was calculated. The Department of Public Service noted that there was a similar error in how grants are recognized in the depreciation calculation for those renewable generation technologies that receive grants. The model was modified to address both these issues and the depreciation schedule was presented in a manner which is much easier for the analyst to follow.

The fifth change, proposed by REV, was to revise how the investment tax credit is considered when establishing the appropriate equity contribution. As noted by REV, the debt and equity percentages which are input assumptions did not reflect the actual debt/equity ratio. The ITC results in an early return of capital and effectively reduces the amount of required equity.

The sixth change was to calculate the term over which debt payments were made based on the loan term assumption specified by the user. This change reduced the potential for errors in the debt repayment schedule.

The seventh change was to modify the layout of the tax depreciation schedule so that it was easier for users to follow and made it easier to check the depreciation calculations and assumptions.

The eighth change was to modify the model so that there were input cells for all major project development, construction and financing costs.

The ninth change was to create a simple instructions tab which provides a brief overview of the changes that users need to make to solve the model.

Q. The Department recommended that the cash flow model assume that there be no assumed income tax liability when calculating the after tax cash flows. Do you agree?

A. Yes. The Department argued that if farm methane projects were assumed to not be able to take advantage of the ITC then the effective tax rate for these projects should be zero. This is a reasonable argument.

Recognizing that farm incomes are minimal, another possible alternative is to consider the ITC and other tax benefits only when the project has taxable income. The required standard offer prices for both alternatives were very close. I have elected to evaluate the alternative proposed by the Department which assumes that the effective tax rate for farm methane projects is zero and there is no ability to utilize the ITCs.

Q. Another structural change that was proposed by the Department for the cash flow model for farm methane projects was to employ two-tier pricing where there are different prices for the assumed term of debt financing and for the period after which the debt is retired. Please comment.

A. While the pricing analysis performed by the Department suggests that two-tiered pricing will result in a lower overall levelized cost (Prefiled Testimony of John Becker, Docket 7533, p. 14), two-tiered pricing results in increased front-loading. This in turn can lead to an increase in the potential for project defaults after the price steps down to the lower second tier price. To the degree that the cash flow continues to be positive after the price steps down this risk is mitigated. The standard contract doesn’t offer any protection for such any event, e.g., there isn’t a requirement for developers to post financial security to cover the amount of front-loading that is forecast to occur. Farm sector representatives suggested that farmers were likely to prefer a more levelized pricing stream. Therefore, I don’t believe that the lower overall price (as measured in terms of levelized costs) offered by two-tier pricing is sufficient compensation for the increased risk of project defaults. I recommend that two-tier pricing not be employed for farm methane projects, but that a portion of the price for farm methane projects escalate at inflation. This is discussed further below.

IV. Recommendations on Financing Assumptions

Q. What are the different financing structures that are available to project developers?

There are a range of different financing structures that are available to project developers. A critical issue for these projects is ensuring efficient utilization of the significant income tax credits and depreciation benefits that they offer. This will be a focus of developers when establishing the financing structure and securing investors.

One alternative that is commonly used for larger renewable generation projects is a tax equity structure which facilitates the utilization of the tax benefits they generate by entering into a partnership with an entity that has a tax "appetite" (i.e., taxable income). There is typically limited leverage in tax equity projects given rules which limit the ability of investors to utilize tax benefits on the economic value of the investor's interest in the partnership. Tax equity investors required returns of 7 to 8% prior to November 2008, with returns increasing in late 2008 and early 2009. (Project Finance Newswire, November 2008, p. 53.) With the economic downturn the number of parties pursuing tax equity projects has shrunk significantly and it isn't clear that the parties that typical provide such financing would be interested in projects of the size offered by the standard offer program. In addition, it is difficult and costly to structure tax equity deals, making this approach more appropriate for larger projects. Moreover, there are sale-leaseback and master lease pass-through structures which are more appropriate for smaller projects and can be employed to ensure that the tax benefits are utilized efficiently.

Another financing structure is non-recourse project financing where project revenues are pledged to make interest payments and to retire the debt. This model is attractive to developers because it can allow for significant leverage of lower cost debt and the debt doesn't affect the borrowing capacity of the developer. To evaluate the proposed project and to structure such an arrangement lenders require a considerable amount of due diligence and documentation. The debt is secured by the project assets, with lenders evaluating projected cash flows to ensure that they are likely to be sufficient to cover debt service payments and operating expenses. To cover unforeseen contingencies cash reserves typically are required to be held in escrow to cover debt service payments and operating expenses. However, there are significant fixed costs for project finance deals. This limits their application to projects with significant capital requirements.

Q. Are projects participating in the standard offer program likely to be of a size large enough to cost-effectively utilize these financing structures?

A. Generally not. However, I expect developers and investors to develop partnerships and financing vehicles that attract investors that can utilize these significant tax benefits. I believe that the significant market response to the standard offer program is an indication that developers are confident that they will be able to develop financing structures that efficiently utilize these tax credits and can access competitively priced debt and equity.

Q. What type of financing structures do you expect project developers that are pursuing renewable energy projects with more limited capital requirements to utilize?

A. As discussed, project financing and tax equity financing is most suited to relatively large projects. Smaller projects are more likely to use more conventional financing sources with debt issued based on the credit of host facility (e.g., big box store) or on more conventional collateral (e.g., real estate for farm methane projects).

The debt issued under such transactions typically are an obligation of the borrower (i.e., recourse) and as such are required by accounting and financial reporting rules to be identified as a financial obligation on its financial statements. The primary advantage of this approach is that lenders typically don't require the same amount of project-related due diligence given that the focus is on the ability of the project sponsor to pay back the loan rather the project to generate sufficient cash flow to repay the loan. This reduces the cost and effort required to secure such loans. However, project proponents with poor or limited credit will have a harder time securing such loans or will be only able to do so on less favorable terms.

Q. In their Prefiled Testimony Mr. Rickerson and Mr. Karcher offered a number of comments on the financing assumptions used in cash flow model. Please review these comments.

A. The Prefiled Testimony of Wilson Rickerson and Matthew Karcher offered a number of reasonable comments on the financing assumptions reflected in the cash flow model. Specifically, they suggested that the model should include: (1) a debt service reserve given that these are typically required for commercial bank loans (p. 4, lines 4-10); (2) an operating reserve account to reflect required cash reserves for maintenance and operating expenses (p. 7); and (3) all transactional costs (i.e., up-front fees, third party legal and consulting costs, internal costs) required to secure such financing ((p. 21, lines 9-12).

Q. Please comment on these suggestions.

A. These are each appropriate and reasonable comments if these standard offer projects are likely to be financed using project finance. However, as discussed I expect that only a limited number of projects participating in the standard offer program will use a formal project finance approach where there is a high degree of leverage and the debt is non-recourse.

Nonetheless, I did assume that the PV projects would employ a project finance structure and included debt service and maintenance reserves in the cash flow model for these projects.

Q. Please summarize your recommendations regarding the appropriate assumptions for the financing approaches to be employed for the standard offer projects.

A. Certainly. As noted in the Prefiled Testimony of Mr. Rickerson and Mr. Karcher there is considerable uncertainty regarding the financing terms that will be available for projects of the scale required by the standard offer program. (Docket 7533, page 17, lines 20-22) Nonetheless, assumptions need to be made regarding the different types of financing structures that will be employed when specifying the cash flow model. There are a number of tax-driven financing structures which are likely to be attractive and are consistent with the assumptions that I make regarding the relatively efficient utilization of tax credits. However, I did not model these given the limited time available, the analytical complexity associated with these structures, and the uncertainty regarding their application.

The basic project structure that I have modeled is a project financed with a combination of debt and equity. For PV projects which have the greatest capital requirements (i.e., solar PV), I assumed that a formal project finance approach would be employed. For these projects I assumed that the lender would require debt service reserves and maintenance and operating expense reserves and that these projects would need to satisfy average debt service coverage ratios of 1.5 and minimum debt service coverage ratios of 1.2.

I assumed that smaller projects will be financed using more conventional loans which are not likely to require cash reserves for debt service or operating expense.

Q. In their Prefiled Testimony Mr. Rickerson and Mr. Karcher question the appropriateness of assuming "continued improvement in credit market conditions by the time projects need financing" as reflected in the cash flow model's debt assumptions. They note that "basing model assumptions on expectations of future conditions rather than what is currently available increases the financing and price risk on the projects."(Docket 7533, p. 21, lines 15-17) Do you agree?

A. Yes, I agree that such an assumption increases project risks. However, as indicated by the analysis presented below, I believe that the financial assumptions that I employ for the cash flow modeling are generally reflective of current financial market conditions. The major assumption that I employ which is not readily available in the current financial market is the assumption regarding the debt term (tenor) which is discussed further below.

Nonetheless, based on the relatively recent conditions in the financial markets where loans where available only for the strongest of projects, the improvements that have been experienced in the financial markets, and indications that financial market conditions will continue to improve; and considering the financing terms that were generally available prior to the collapse of these markets, I believe that this assumption (i.e., that financial market conditions continue to improve) represents a reasonable risk for project developers to bear and manage.

The pricing terms offered in the standard offer contract are set for a 20-year term, with the price paid by Vermont ratepayers for the contract term based in part on the assumptions used in the model. Assuming that financial market conditions will not continue to improve when there is a strong likelihood that they will would require Vermont ratepayers to pay higher costs for these resources and allow developers to realize a windfall if financial market conditions improve as anticipated. In the last six months the interest rate on long-term BAA bonds which are indicative of terms that could be available for the most financially sound larger generation projects have declined by almost 175 basis points.

(http://www.federalreserve.gov/datadownload/Choose.aspx?rel=H.15) While I don't anticipate such a significant improvement in the credit markets over the next six months, this provides an indication regarding the potential costs to consumers and windfall to developers from a static perspective regarding the financing terms available to developers.

Furthermore, for PV projects the market response suggests that these assumptions aren't a barrier to project development. As I have suggested, PV project developers appear to be willing to take risks associated with the continued decline in the costs of PV modules so why wouldn't they be willing to accept a similar risks regarding continued improvement in credit market conditions. In both instances, developers' risks are mitigated by the fact that their security deposit isn't at risk for the first 12 months after contract execution.

Q. What evidence is there that conditions in the credit markets are likely to continue to improve?

A. The most compelling evidence that credit markets are likely to continue to improve is probably provided by credit spreads (i.e., the differences between the yields on government and corporate debt). Figure 1~~Figure 1~~illustrates credit spreads over the last five years and demonstrates how credit spreads have improved dramatically relative to the 4th Quarter of 2008 and 1st Quarter of 2009. Nonetheless, they continue to be considerably greater than they have been historically. Specifically, while the credit spread between 20- year Government Bonds and Corporate BAA rated bonds averaged

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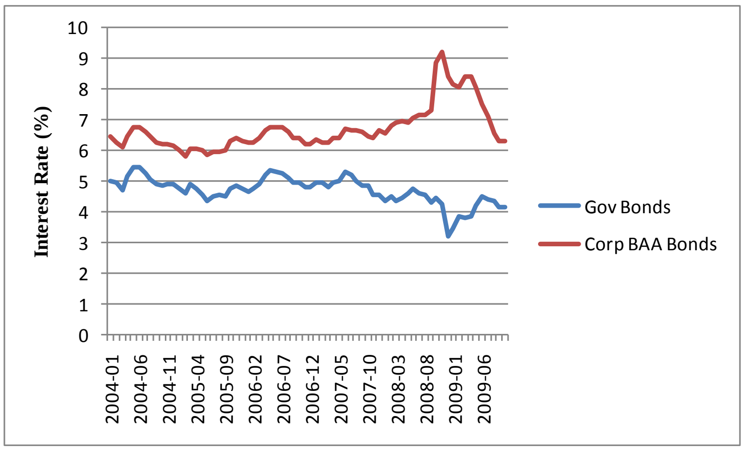
about 140 basis points from 2004 to 2006, the average equivalent credit spread in October 2009 was over 210 basis points, 50% higher.

Figure 1: Review of Credit Spreads



Q. **Please summarize your opinion regarding the appropriate perspective on financial market conditions.**

A. I believe that it is appropriate to take a prospective view of future financial market conditions when establishing the appropriate assumptions for financing these standard offer projects.

Q. **Before reviewing your assumptions regarding the appropriate cost of debt, please provide your perspective regarding how lenders are likely to perceive the risks of these standard offer projects?**

A. This is an important issue for projects that secure their debt using project finance. Under project finance lenders will establish the cost and tenor of debt based on their assessment of the project's overall risk and general credit market conditions at the time of the financing. With the program underpinned by legislation and a Board order approving the contract, there is likely to be relatively limited regulatory risk. The ultimate buyers for the power are the Vermont Distribution Utilities. There isn't a single counterparty; this should reduce the perceived credit risks to the seller. Therefore, it is believed that the standard offer contract will not be viewed as unduly risky by lenders.

Q. On what basis have you estimated the appropriate cost of debt for these projects?

A. I have relied on information available regarding the financing terms for several recent project financings. These offer insights on the terms being offered for well structured projects with long term power purchase agreements. Power Advisory's September report (*Independent Analysis of Prices Required for Vermont's Standard Offer*) reviewed the deal secured by Boralex, a Canadian based developer who financed several wind projects in early September with an aggregate capacity of 40 MW. Boralex was able to secure a 5-year loan that will be amortized over 19 years at a rate of 6.4%. While this was a Canadian loan the US and Canadian debt market are relatively well integrated, with Canadian bonds offering interest rates that are about 50 basis points below equivalent US bonds.

A review of recent debt transactions indicates that pricing for mini-perm loans (referenced in the Prefiled Testimony of Mr. Rickerson and Mr. Karcher) ranges from 300 to 325 basis points above LIBOR (the London Inter-Bank Offer Rate). (Exhibit ___JCD-2) LIBOR is the rate at which banks lend to each other; is set daily and as such a variable rate. Parties can secure a fixed rate using an interest rate swap. The current

LIBOR rate for a 1 year loan is 1.09%. (http://www.bankrate.com/rates/interest-rates/1-year-libor.aspx) Adding 325 basis points results in a 4.34% rate. Adding an additional 248 basis points for a five-year interest rate swap, yields an effective interest rate of 6.82%. (http://www.federalreserve.gov/datadownload/Choose.aspx?rel=H.15) I offer this as a high level estimate of the interest rates that that are likely to be secured by standard offer projects.

However, it is reasonable to expect further declines in interest rates. At a recent conference, bankers expected to see a drop in debt pricing and an extension in loan tenors, with the LIBOR premium dropping from 300 basis points toward 200 basis points. (*Power Finance & Risk*, "Longer Tenors, Tighter Pricing Forecast", October 26, 2009, p. 1, 4).

Based on this information, I believe that a 7.5% debt rate is a reasonable rate to use. This rate is 70 basis points above indications regarding what pricing for a mini perm loan might be and provides a margin for the uncertainty regarding the types of loans that will be ultimately utilized and to cover refinancing costs. The prospect for further declines in interest rates provide an additional margin of conservatism.

I used 7.5% for the cost of debt for all of the projects except farm methane for which I used 5.5%, small wind (15 kW) for which I used 5.5%, and small wind (100 kW) for which I used 6.0%.

Q. What role can loans from Vermont Economic Development Authority (VEDA) and the Community Economic Development Fund (CEDF) play in providing low cost debt?

A. These are another possible source of debt which can lower the effective cost of borrowing for these projects. While I have not explicitly considered the cost of debt offered by these sources, the availability of low cost debt from these sources tempers the risk of higher interest rates than I have assumed.

Q. What do you recommend for the debt term?

A. There are two alternatives: (1) a mini-perm structure such as discussed in the Prefiled Testimony of Wilson Rickerson and Mathew Karcher is used and the project is refinanced, which requires that assumptions be made regarding the terms under which the project would be refinanced; or (2) longer term debt is secured. Both require some speculation. The mini perm structure is being used for project finance deals. To the degree that the debt is recourse to the borrower then longer term debt is generally available, depending on the credit of the borrower.

Over the 20-year term of the standard offer contract developers will be able to refinance their projects to the degree that they can secure more favorable terms. Therefore, the mini-perm structure that Mr. Rickerson and Mr. Karcher discussed in their Prefiled Testimony can be viewed as a bridge to longer term financing. While the cash flow model doesn't consider the transaction costs for a second loan, if the project owner is able to elect when it refinances it is reasonable to expect that it will be in a more favorable interest rate environment where the lower interest costs more than compensate for these transaction costs.

Furthermore, longer debt terms were available before the credit crisis for project finance structures. The financial markets are continuing to improve and there are indications that lenders are returning to the market. For example, John Hancock recently announced that it was returning to the market and life insurance companies offer long-term fixed rate loans for strong projects. Based on these considerations, I have assumed a 17-year debt term for most technologies, except for farm methane where I assumed a 10-year debt term as discussed in my Direct Testimony; ~~and~~ small wind (15 kW)where I also assumed a 10-year debt term and solar PV where I assumed an 18-year debt term given the 25-year contract term.

Q. The cash flow model needs a forecast of inflation. Could you please present your recommendations for the appropriate inflation forecast?

A. Certainly. However, before discussing this I would like to discuss the appropriate price index that should be used to measure the impact of inflation on the operating and maintenance costs of the eligible standard offer generating technologies. There are two primary alternatives: (1) the CPI (Consumer Price Index) which is the most widely known and used price index; and (2) the implicit GDP deflator which is the difference between the Gross Domestic Product (GDP) in nominal (current) dollars and the GDP in real (constant) dollars.

The CPI measures the cost of a basket of goods purchased by an urban consumer. Therefore, it has relatively heavy weights on the cost of housing, food and transportation, including automobile purchases, maintenance and fuel. The CPI is essentially a cost-of-living index and isn't necessarily an appropriate index for measuring the increases in costs of operating and maintaining a renewable generating facility. The CPI is more appropriate where labor and fuel costs are a major cost driver for such facilities.

The implicit GDP deflator measures the average increase in prices for all goods and services in the economy. Unlike the CPI it isn't based on a fixed basket of goods. The implicit GDP inflator is a broader measure of inflation which allows for the substitution of cost inputs. It reflects elements of cost like the cost of purchased materials or equipment that are not in the CPI.

The inflation forecast recommended by the Department is for the implicit GDP deflator. I also believe that the implicit GDP deflator is a better price index to use for forecasting and measuring the increases in the operating and maintenance costs of renewable generation facilities. If the Board elects to have a portion of standard offer prices escalate with inflation, I recommend that the implicit GDP deflator be used as the inflation index.

Q. Do you have a recommendation regarding the appropriate forecast for the implicit GDP deflator that should be used in the cash flow model?

A. Yes. The Department has adopted and recommends the latest forecast from Economics.com. which results in a compound annual growth rate (CAGR) for inflation of 1.5%. To assess its reasonableness, I have looked at other available long-term forecasts of US inflation. The Energy Information Administration of the US Department of Energy publishes an annual long-term energy outlook. In the assumptions to its latest (March 2009) publication, it uses as its reference case a CAGR from 2007 to 2030 of 1.6% for a "GDP Chain-type price index" which is essentially the implicit GPD deflator. (http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf, p. 159)

Another readily available inflation forecast is from Consensus Economics and provides a long-term US forecast for CPI. Consensus Economics surveys economic forecasters and publishes consensus forecasts derived from these surveys. They survey long-term forecasters twice a year. Their most recent (October 2009) long-term forecast for the United States projects a CAGR of US CPI from 2009 to 2019 of 2.0%. The forecast shows inflation rates ramping up gradually, reaching a projected 2.4% CAGR for the last four years of the forecast (2015-2019). If the 2.4% CPI inflation rate were to hold for the next 10 years, the CAGR for the 20-year period ending in 2030 would be 2.2%.

This Consensus Economics forecast needs to be adjusted to reflect the implicit GDP deflator. To do this I compared the CPI to the implicit GDP deflator. The CPI is noticeably more volatile than the implicit GDP deflator, in part because of the weighting in the CPI of such volatile prices as those of housing, fuel, and food. Further, inflation measured by the CPI tends to be higher than the Implicit GDP deflator, by about 0.6 % over the last 20 to 40 years. Assuming that this historical relationship is maintained, the Consensus Forecast for CPI supports an implicit GDP deflator forecast of 1.6%.

These three available forecasts are generally consistent with each other and project long-run average inflation rates as measured by the implicit GDP inflator of 1.5% to 1.6% per year. With two of these forecasts supporting an inflation forecast of 1.6%, I used an inflation forecast of 1.6% in the cash flow modeling.

Q. You modified the model to allow a portion of the contract price to escalate by inflation. If the Board were to implement such a pricing framework do you have a

recommendation regarding the proportion of the contract price that should escalate by inflation?

A. Yes, I do. The objective of allowing a portion of the contract price to escalate by inflation is to mitigate the risk to project owners of changes in the rate of inflation. Therefore, the proportion of the contract price that escalates by inflation should approximate the proportion of total project costs that escalate by inflation. Ontario's standard offer and feed-in tariff program allowed 20% of the contract price to escalate by inflation based on such an estimate.

The stability of debt service coverage ratios and how often cash flows become negative provides an indication regarding the appropriate portion of the contract price that should escalate by inflation. While different proportions could be used for different technologies, for administrative simplicity I recommend that if the Board implements this pricing approach that one percentage be employed for those technologies where it is appropriate to escalate contract prices by inflation. Based on the modeling that I performed, I recommend that 30% of the contract price be escalated by inflation. Furthermore, I recommend that contract prices for solar PV projects be flat given the limited proportion of project costs that escalate for these projects. I also recommend that the contract price for small wind projects (both 100 kW and 15 kW) also not escalate.

Q. What are your assumptions regarding the ability of these projects to efficiently utilize the investment tax credits generated?

A. As discussed, given the significant portion of the project value that is reflected by investment tax credits, I expect developers and investors to develop partnerships and financing vehicles that can utilize efficiently these significant tax benefits. The most significant challenge is efficiently utilizing the state investment tax credits given the limited pool of Vermont taxpayers that are in the highest marginal tax bracket. Based on discussions with a party that structures partnerships to efficiently utilize these tax benefits, I understand that a separate investment vehicle can be utilized for the state investment tax credits. This would limit the need to draw upon Vermont investors for all of the investment tax credits. Therefore, for the cash flow modeling I have assumed that 60% of the state investment tax credit is utilized in the first year for the non-solar PV technologies and that for solar PV 70% of the ITC is utilized over two years. I assume that the federal ITC is fully utilized given the broader market available to the federal ITC.

Q. In your opinion are there any adjustments to the project cost estimates or the return on equity earned as allowed by the Act that should be considered by the Board?

A. Yes. While I am not a lawyer and thus not offering a legal opinion, the Act indicates that the Board should consider adjustments to assumptions regarding costs or the return on equity to the degree to which "the price provides a sufficient incentive for the rapid development and commissioning of plants and does not exceed the amount needed to provide such an incentive." (Sec. 4. 30 V.S.A.§8005 (b)(2)(B)(i)(III)) As discussed, the significant market response to the interim prices suggests that these prices are too high. Furthermore, consumers that implement renewable energy projects at their own facilities do this for many reasons other than just the financial returns that they earn. Many of these parties employ these renewable energy technologies because they are committed to improving the environment and as a result are willing to accept a much lower rate of return. Therefore, for smaller standard offer projects that are most likely to be implemented by homeowners or commercial customers who value the environmental benefits of these technologies a lower return on equity may be appropriate. These parties typically are interested in recovering their costs and securing a small return on their investment. I believe that a return on equity of eight percent is reasonable for these parties.

Q. In their Prefiled Testimony, Mr. Rickerson and Mr. Karcher and Mr. Stover and Mr. Basa note that single wind turbine projects are riskier than much larger multi-unit projects. Do you agree?

A. Yes. Single turbine wind projects do represent a greater operating risk than a multi-unit project. However, of the nine wind projects for which developers have submitted applications, six projects appear to be under development by a party that is pursuing multiple standard offer projects. This allows them to spread their development and operating risks over multiple projects. Furthermore, the three remaining projects appear to be under development at host sites where the project would be owned and operated by the site owner. Under such an arrangement, the facility is more likely to be financed using a conventional real estate or more traditional recourse loan. Under such a financing structure the project's operating risk is unlikely to have an impact on the terms offered by the lender. While this operating risk will reside with the project owner under such a financing structure, the cash flow model includes the cost of insurance and it is incumbent on the project owner to select technologies with demonstrated operating histories that will help manage this risk.

VI. Review of Policy Considerations

Q. In your opinion should the Board employ a greater level of granularity than specified by the Act?

A. No. In my opinion, the Board should not employ a greater level of granularity than specified in the Act. However, one's opinion regarding granularity is driven primarily by objectives and how these different objectives are balanced. Granularity allows a wider range of project types and technologies to participate in a standard offer program. Therefore, if one's objective is to promote the broader adoption of a wide range of renewable energy technologies then greater granularity can be appropriate.

However, as the Board noted in its decision in Docket 7523 regarding interim standard offer rates, there is broad recognition of economies of scale in electricity generation from renewables; costs for projects at a smaller scale are generally higher than costs for projects at a larger scale. Therefore, the prices offered to smaller-scale projects need to be higher than for larger projects to the degree that developers earn equivalent returns. These higher prices raise the costs to consumers of satisfying the environmental objectives promoted by renewable energy projects. However, if one accepts that developers of smaller projects that are typically owned by the host are more willing to accept a lower return then there is less justification for granularity.

The composition of proposed projects that submitted applications for contracts indicates that the standard offer program has achieved a reasonable level of granularity. (Prefiled Testimony of David Lamont, Docket 7533, p. 7) Increased granularity should therefore be considered only if these results are seen to be unsatisfactory in that too few parties offering smaller projects were able to take part or that there was not enough diversity in the supply offered.

VII. Review of Technology Specific Assumptions

Q. Do you any general comments or clarifications that you would like to offer regarding your assumptions for the various eligible standard offer renewable energy technologies that you modeled?

A. Yes, I do. I believe that it is important that the standard offer program send a price signal that incents the development of efficient renewable energy projects that are located at sites with favorable renewable energy resources and employ among the most efficient eligible renewable energy technologies. Therefore, the technology cost and performance assumptions that I employ reflect such efficient projects.

One change that I made to the cash flow modeling for all projects was to increase the required amount of working capital to reflect three months of project operations and maintenance expenses, except for the farm methane projects where I kept it at one and one-half months.

Q. Please review your recommendations regarding the assumptions for landfill gas projects.

A. I recommend that the Board adopt the assumptions for the cost and performance of landfill gas (LFG) projects proposed by Douglas C. Smith of Green Mountain Power. These assumptions are outlined in his Prefiled Testimony, with additional support provided in Notes from an October 23, 2009 telephone conversation between Mr. Smith and George Aronson of CommonWealth Resource Management Corporation (CRMC), provided as part of Responses of Green Mountain Power Corporation to REV First Set of Discovery Questions. CRMC focuses on LFG project development and offers extensive experience with respect to the evaluation of LFG project costs.

REV had provided estimates of the costs and performance of landfill gas projects to the Cost Analysis Subgroup in Docket 7523. These estimates suggested that landfill gas project costs were about 25~~7~~ cents per kWh which is dramatically higher than the various feed-in tariff rates that have been proposed for landfill gas projects. Furthermore, this proposed pricing was contrary to my professional experience where I have found that LFG projects are typically among the most cost-effective renewable energy resources.

The assumptions that I am recommending are shown in Table 2~~**Table 2**~~. The $2,000/kW capital cost is assumed to reflect all project costs including development, interconnection, and financing costs as well as any relevant debt service and operating expense reserves. The installed cost for the genset is estimated to be approximately $1,000/kW, so this $2,000/kW capital cost is conservative (most likely high) according to CRMC.

In addition, I assumed that the majority of project costs (92% for the small LFG project) qualified for 15-year Modified Accelerated Cost Recover System (MACRS).

Table 2: Landfill Gas Cost and Performance Assumptions

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Project	Large Landfill	Small Landfill
Project Size (kW)	1,500	600
Project All-in Capital Cost ($/kW)	$ 2,000	$ 2,000
O&M Expense ($/MWh)	20	30
Heat Rate (btu/kWh)	12,000	12,000
Landfill Operating & Capital Costs ($/MMBtu)	$ 0.80	$ 0.80
Capacity Factor	90%	90%
Equipment Useful Life (years)	20	20
Federal and State Investment Tax Credit	34.3%	34.3%

Q. In his Prefiled Testimony, Mr. Smith recommended that separate prices be developed for large and small landfill gas projects. Do you agree?

A. Yes. While I don't believe that further granularity is appropriate for most of the eligible standard offer technologies, I do believe that it is appropriate for small landfill gas projects. Small landfill gas projects offer the lowest prices of any of the standard offer technologies, other than large landfill gas projects. Therefore, adopting a separate price for small landfill gas projects is likely to reduce the costs of the standard offer program.

Q. What is the resulting standard offer price required to achieve a 12.13% after tax return on equity for the two sizes of LFG projects you evaluated?

A. Table 3~~Table 3~~ presents the projected standard offer prices for large (1.5 MW) and small (600 kW) landfill gas projects assuming a nominal levelized price which is constant across the 20-year contract term and if 30% of the price escalates based on an inflation index which is assumed to be the implicit GDP deflator. Table 3~~Table 3~~ also indicates the debt/equity ratio and average debt service coverage ratios for these different projects and pricing scenarios.

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Table 3: Landfill Gas Standard Offer Prices and Financing Variables

No Escalation	Large Landfill	Small Landfill
Standard Offer Price ($/MWh)	$ 74	$ 85
Debt/Equity Ratio	45/55	45/55
Ave. Debt Service Coverage	1.9	1.8
Escalation @ 30% of Inflation	**Large Landfill**	**Small Landfill**
Standard Offer Price ($/MWh)	$ 70	$ 82
Debt/Equity Ratio	50/50	50/50
Ave. Debt Service Coverage	1.6	1.6

Q. Please review your recommendations regarding the assumptions for wind generation projects.

A. The wind generation project cost and performance assumptions that I am recommending are presented in Table 4~~Table 4~~. Table 4~~Table 4~~ also identifies assumptions for a small wind project which is assumed to be a wind turbine with a rated capacity of 15 kW. The capital cost estimate for the 15 kW project is based on the figure presented on page 16 of the Prefiled Testimony of Wilson Rickerson and Matthew Karcher. This table indicates an average installed cost (the figure identifies them as average turbine price, but the text refers to them as installed costs) of approximately $6,000/kW. I would expect that an efficient project would be able to achieve lower costs, but used this cost estimate to be conservative given the uncertainty regarding what is included in these costs estimates. I included $1,000 for interconnection costs based on the interconnection cost estimate for small projects developed by Martin Bowen III of Central Vermont Public Service and estimated that project development and engineering costs would be an additional $5,000.

Comment [JD1]: Note price for small LFG with no escalation was $86/MWh and for large LFG with escalation was $71/MWh

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The higher capital costs for the 100 kW relative to the 15 kW wind projects are counter intuitive. The 100 kW capital cost estimates were developed by Northern Power Systems. Their estimate is higher than the average installed cost presented for a 100 kW turbine presented in the referenced figure (page 16) presented in Mr. Rickerson and Mr. Karcher's Prefiled Testimony.

Table 4: Wind Generation Cost and Performance Assumptions

Attribute\Project	Large Wind	Small Wind	Small Wind
Project Size (kW)	1,500	100	15
Project All-in Capital Cost ($/kW)	$ 3,000	$ 6,750	$ 6,400
O&M Expense ($/kW)	64	114	92
State Grant Before Tax ($/kW)		$ 2,500	$ 1,333
Federal and State Investment Tax Credit	34.3%	34.3%	34.3%
Capacity Factor	26.6%	23.8%	19.0%
Equipment Useful Life (years)	25	20	20

Comment [JD2]: Increased assumed useful life for large wind from 20 years to 25 years

Q. What is the resulting standard offer price required to achieve a 12.13% after tax return on equity for the three different size wind projects you evaluated?

A. Table 5~~Table 5~~ presents the standard offer prices assuming no annual escalation in these prices for the three different sizes of wind projects evaluated. If 30% of the contract price were to escalate with an inflation index, then the initial standard offer price for a large wind project would be $114~~06~~/MWh.

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As discussed, a case can be made that the return required for parties that are constructing smaller renewable projects at their own facilities (i.e., home or commercial space) is well below that of a traditional investor. At an 8% return on equity, the standard offer price would be $238~~9~~/MWh for a 15 kW wind project and $237~~3~~/MWh for a 100 kW wind project.

Table 5: Wind Project Standard Offer Prices and Financing Variables

No Escalation	Large Wind	Small Wind	Small Wind
Project Size (kW)	1,500	100	15
Standard Offer Price ($/MWh)	$ 118	$ 258	$ 266
Debt Term (years)	17	17	10
Debt/Equity Ratio	40/60	65/35	60/40
Ave. Debt Service Coverage	1.6	1.3	NA

Comment [JD3]: Price for small wind (100 kW) increased from $255/MWh to $258/MWh and small wind (15kW) decreased to $266/MWh from $267/MWh

Q. Please review your recommendations regarding the assumptions for hydroelectric projects.

A. The hydroelectric project cost and performance assumptions that I am recommending are presented in Table 6~~Table 6~~. These assumptions are generally consistent with those used in the September 12th Power Advisory Report, except that the methodology for establishing property taxes has changed with a resulting impact on operations and maintenance expenses and, as discussed, I have changed my treatment of federal and state investment tax credits.

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Table 6: Hydroelectric Cost and Performance Assumptions

Project Size (kW)	1,278
Project All-in Capital Cost ($/kW)	$ 4,173
O&M Expense ($/kW)	$ 161
Federal and State Investment Tax Credit	34.3%
Capacity Factor	44.9%
Equipment Useful Life (years)	30

A. Table 7~~Table 7~~ presents the standard offer prices that I calculated assuming 30% of the contract price escalates with inflation and the contract price is constant over the contract term.

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Table 7: Hydroelectric Standard Offer Prices and Financial Variables

	30% Esc.		Flat	
Standard Offer Price ($/MWh)	$	136	$	140
Debt/Equity Ratio		55/45		55/45
Ave. Debt Service Coverage		1.6		1.6

Q. Please review your recommendations regarding the assumptions for solar PV projects.

A. The solar PV project cost and performance assumptions that I am recommending are presented in Table 8~~Table 8~~. These assumptions are generally consistent with those used in the September 12th Independent Report. However, I updated the project capital cost estimates to reflect more recent information regarding the pricing for solar PV modules. Navigant Consulting notes that average selling prices for PV module have declined by 40% in 2009 relative to 2008. (http://www.navigantconsulting.com/emarketing/Documents/Energy/SolarPower09NavigantConsultingExecBreakfastBriefingFinal.pdf, p. 10) Recognizing that modules represents a little over 50% of the cost of a PV system for larger systems and assuming price declines of other project costs of from 1% to 7.5%, this translates into a total cost reduction of about 25%. The Massachusetts Technology Cost cost estimates that were the basis for the original cost estimates that I used in Power Advisory's September 2009 Report to the Board are assumed to reflect about one-third of these realized price reductions. Therefore, I applied an additional 16.67% cost reduction to the $5.70/watt dc base cost estimate. This produces the current PV capital cost estimate of $4.75/watt dc. The original data source for this estimate indicated that these were installed costs. I

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assume that these estimates include all major capital cost components and reflects any developer incurred financing costs.

Given the dramatic declines experienced, the significant pricing pressures in the market, the significant market response to the interim prices, I also present prices for a second scenario which assumes an additional 10% reduction in prices are achieved.

I also funded 6 months of debt service reserve and reflected operating reserve account funding of 4.5 months in addition to 1.5 months which is reserved for working capital. I have also reflected annual output degradation of 0.71% based on a commonly used NREL estimate. (http://www.nrel.gov/docs/fy02osti/31455.pdf)

Table 8: Solar PV Cost and Performance Assumptions

	Current Cost	10% Reduction
Project All-in Capital Cost ($/kW dc)	$ 4,750	$ 4,275
O&M Expense ($/kW)	54	50
Federal and State Investment Tax Credit	51.0%	51.0%
Debt Service Reserve (Months)	6	6
Capacity Factor	14%	14%
Annual Output Degradation	0.71%	0.71%
Equipment Useful Life (years)	25	25
Contract Term (years)	25	25

Comment [JD4]: O&M expense increased from $49/kW to $50/kW for 10% Cost Reduction scenario

Q. What is the resulting standard offer price required to achieve a 12.13% after tax return on equity for the PV projects you evaluated?

A. The standard offer prices for the two pricing scenarios evaluated are presented in Table 9~~Table 9~~. Given the relatively limited operating and maintenance costs for solar PV projects, I recommend that there be no escalation in their contract price to account for the impact of inflation on these projects.

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Table 9: Solar PV Standard Offer Prices and Financial Variables

No Escalation	Current Cost	10% Reduction
Standard Offer Price ($/MWh)	$ 276	$ 251
Debt/Equity Ratio	35/65	35/65
Ave. Debt Service Coverage	1.5	1.5

Q. Please review your recommendations regarding the assumptions for farm methane projects.

A. Certainly. Table 10~~Table 10~~ reviews the farm methane cost and performance assumptions that were used in the cash flow modeling. These assumptions are generally consistent with those used in Power Advisory's September 12th Report. These assumptions were originally provided by the Vermont Department of Agriculture, Food & Markets (Department of Agriculture). The Department of Agriculture argued that given current economic conditions farmers were unable to utilize the ITCs generated by the project. Therefore, for these pricing scenarios we assumed that there was no taxable income to utilize the project's tax benefits.

Table 10: Farm Methane Costs and Performance Assumptions

Net Capacity (kW)	300
Project All-in Capital Cost ($/kW)	$ 7,628
Grant ($/kW) before tax	$ 1,928
O&M Expense ($/kW)	767
Capacity Factor	76.5%
Offsetting Revenue (per year)	$ 95,000
Debt Term	10
Contract Term (years)	20

Q. Please review the standard offer prices that you calculated for farm methane projects.

Comment [JD5]: Prices increased from $272/MWh to $276/MWh for "Current Cost" and from $248/MWh to $251/MWh for 10% Reduction

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A. Certainly. I calculated the appropriate standard offer prices for farm methane projects under a range of different conditions: assuming that (1) the standard offer price was constant over the 20-year contract term; (2) 30% of the standard offer price escalated by inflation; (3) with and without revenues from the sale of renewable energy certificates (RECs); and (4) at an 12.13% after tax return on equity and 8% after tax return on equity. The results of these various pricing scenarios are presented in Table 11.

Table 11: Farm Methane Standard Offer Prices and Financial Variables

No REC Value @ 12.13% ROE	Flat	30% Esc.
Standard Offer Price ($/MWh)	$ 171	$ 166
Debt/Equity Ratio	65/35	65/35
Ave. Debt Service Coverage	1.3	1.3

RECs @ $25/MWh @ 12.13% ROE	Flat	30% Esc.
Standard Offer Price ($/MWh)	$ 142	$ 138
Debt/Equity Ratio	65/35	65/35
Ave. Debt Service Coverage	1.3	1.3

No REC Value @ 8% ROE	Flat	30% Esc.
Standard Offer Price ($/MWh)	$ 157	$ 151
Debt/Equity Ratio	65/35	65/35
Ave. Debt Service Coverage	1.3	1.3

Q. What was the basis for the renewable energy certificate (REC) pricing of $25/MWh that you assumed?

A. The Direct Testimony of Bruce W. Bentley, David J. Dunn and Martin Bowen III reviews Central Vermont Public Service's (CVPS's) Cow Power Program which provides participating farms with $40/MWh for RECs generated. Mr. Dunn noted that the program's "supply/demand balance is nearly matched. With some marketing and continued positive customer acceptance, CVPS is hoping to keep demand ahead of supply so that the RECs and other attributes acquired from farm producers for retail customers can all be resold to tariff participants." (Docket 7533, p. 9-10, lines 25-28 and 1). However, thirteen farm methane projects offering 3,588 kW of capacity submitted applications for standard offer contracts and these applications have been accepted for processing. While there will likely be some level of project attrition, an increase in farm methane generation capacity of the magnitude that is likely suggests that this supply/demand balance is unlikely to be maintained, with a resulting surplus of supply. However, participation in the Cow Power Program is on a first come, first served basis. Therefore, I believe that there is a considerable risk that subsequent farm methane projects will not receive the $40/MWh price available in the Cow Power Program. Without the benefit of the Cow Power Program, the value of the RECs generated by these projects will be determined by market prices. I have used $25/MWh as an estimate of the market value of RECs in New England. I assume that these REC prices will escalate annually at a 1% real rate or 2.6% nominal rate.

Q. Do you have recommendations regarding the appropriate cost and performance estimates for biomass projects?

A. No, I do not. I don't have any professional experience with biomass projects of the scale required to participate in the standard offer program. In my experience biomass projects for power generation are seven to twenty times the maximum size permitted by the standard offer program.

Q. Do you have comments on the biomass project price estimates proposed by Timothy M. Maker and outlined by Wilson Rickerson and Matthew Karcher?

A. Yes. The Prefiled Testimony of Wilson Rickerson and Matthew Karcher indicates that the standard offer price for a project with a thermal load profile that allows the project to run throughout the year would be $296/MWh and for a project with a seasonal thermal demand would be $574/MWh. Biomass projects of this size are designed and operated to utilize efficiently the thermal energy produced. However, no credit was given to the value of this thermal energy in the cash flow analysis. (REV Response to Mr. Dalton's First Set of Information Requests, Response 7, p. 5.) As a point of reference, a biomass project being evaluated by Brattleboro is forecast to generate thermal revenues which are about 50% of the electricity revenues. (http://www.reformer.com/opinion/ci_13806366) Failing to consider this revenue calls into question the reasonableness of these estimates.

These prices are over twice and four times, respectively, the standard offer price adopted by the Board in its initial price determinations. Yet, the amount of capacity offered by biomass projects exceeded the 12.5 MW cap allowed for any one technology. This also calls into question the reasonableness of the standard offer price proposed by Mr. Rickerson and Mr. Karcher.

In his Prefiled Testimony Mr. Maker suggests that "market economics do not support it [biomass] at this scale".(Docket 7533, page 9, line 3) These prices support this assertion.

Therefore, based on the significant market response to the legislatively established interim standard offer price and questions regarding the reasonableness of the

REV biomass cost estimates, I recommend that the Board consider a price which is no higher than the legislatively established interim price.

Q. Does this conclude your rebuttal testimony?

A. Yes.